The cost of capital challenge in delivering a just and equitable transition for shipping

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UMAS is an independent commercial consultancy dedicated to catalysing the decarbonisation of the shipping industry. With our deep industry expertise, exceptional analytical capabilities and state-of-the-art proprietary models, we support our clients in navigating the complexities of this transition by providing groundbreaking data, analyses and insights. Internationally recognised for our work, UMAS delivers bespoke consultancy services to the maritime sector (including owners/operators, charterers, OEMs, and energy providers), alongside regulators, governments, and NGOs.

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About UCL

The UCL Energy Institute hosts a world leading research group which aims to accelerate the transition to an equitable and sustainable energy and trade system within the context of the ocean. The Shipping and Oceans Research Group's multi-disciplinary work on the shipping and ocean system leverages advanced data analytics, cutting-edge modelling, and rigorous research methods, providing crucial insights for decision-makers in both policy and industry. The group focuses on three core areas: analysing big data to understand the drivers of shipping emissions, developing models and frameworks to explore the path toward zero-emission shipping, and conducting social science research to examine the policy and commercial structures that enable the decarbonisation of the shipping sector.

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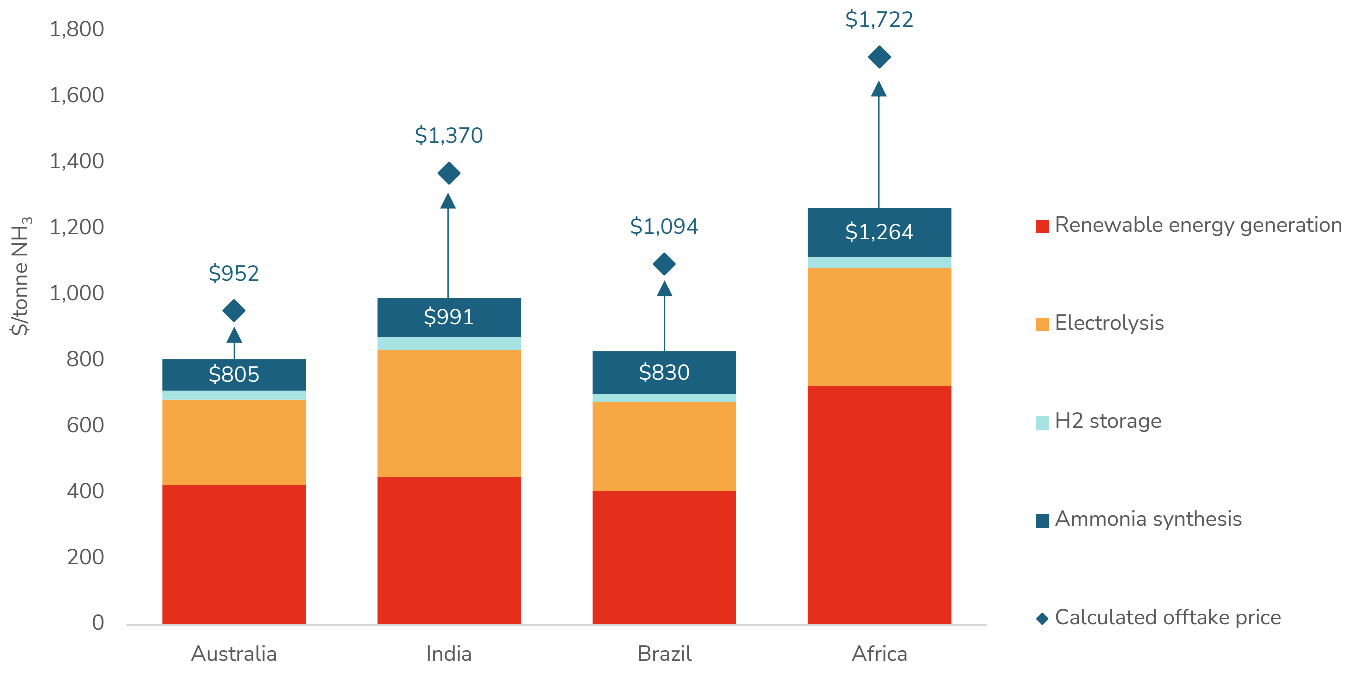
Executive summary

The findings indicate that similarly sized large-scale projects (i.e. controlling for economies of scale) in Brazil, India and Africa would all be uncompetitive relative to projects in Australia, despite comparable or better quality renewable energy resources.

Australia's advantage comes from projects which are more highly leveraged, and also benefit from a lower cost of debt and lower target equity return. Compiling reported values for these parameters indicates a WACC (Weighted Average Cost of Capital) for Australian e-ammonia projects of less than 5%, a range of 8% to 10% for Brazilian / Indian projects, and 8% to 20% for African e-ammonia projects. The cost of capital differences more than compensate for any differential in renewables energy quality, and thus favour the Australian project.

Through the application of levelised cost calculations and project finance modelling, the report also highlights that there is a wide range between the long-run (WACC-based) cost of e-ammonia production (approximately $800/tonne NH_3 in the lowest cost locations) and the initial offtake prices that would be needed to secure project-finance investments ($950 to $1,700/tonne NH_3)—as shown in the chart below. These offtake prices underscore the importance of policy support that offers certainty and sufficient reward in triggering early adoption.

Breakdown of LCOAs and the required offtake price derived for each country / region



This study did not intend to provide an exhaustive assessment of potential projects or their geographies: many other countries have promising renewables resources and may become competitive producers of e-fuels in the future. There are very likely potential projects that are better and more competitive than those estimated from the generalised statistics and assumptions used in this paper.

The representative sample of locations in this study are instead intended to highlight that as long as IMO policy to incentivise energy transition solely or predominantly consists of an 'equity blind' reward mechanism (e.g. a passive allocation of revenues to subsidise e-fuel production), it is more likely to stimulate projects in developed economies. This approach risks perpetuating existing under-investment in many locations that are better suited in terms of renewables resources, but are subject to capacity constraints, lack of capital and/or high cost of capital. If this were the case, the IMO's policy would be reinforcing existing disadvantages and inequities for these countries, and "leaving countries behind", rather than "contributing to a just and equitable transition".

In light of this, the report assessed how the expected inequity in access to and costs of capital could be corrected for. Two tools were considered: 1) grants—essentially providing zero-cost finance for projects in low-income countries; and 2) concessional finance—below-market-rate loans associated with economic development. Under appropriate parameters, these tools can unlock an equitable distribution of investment. For example, to spread $400 billion in capital equitably across the four sample countries / regions selected in this study, an additional $47 billion would be needed in grants (or a combination of grants and concessional finance).

Unlocking an equitable distribution of e-fuel investment (e.g. equal amounts across countries of different income status) is not equivalent to addressing the negative impacts that disproportionately impact low-income countries relative to high-income countries. However, this would at least mean that the distribution of investment from equity-blind rewards did not compound the inequities already inherent in the generalised increase in transport cost associated with shipping's transition to use of renewable fuels.

Introduction

The International Maritime Organization (IMO) reached historic agreement in 2023 with the adoption of its Revised GHG Strategy, which cemented clear targets for reductions in absolute GHG emissions from international shipping by 2030, 2040 and 2050[1]. Member states are now gearing up for the key negotiations around the basket of mid-term measures that will be crucial to delivering these targets. However, while the current debate may focus on the measures that will mandate direct action by the shipping industry, the scope and scale of the transition will require investment from a far broader set of stakeholders.

The trajectory set by the IMO's Revised GHG Strategy means that international shipping will need access to large volumes—between 200 and 300 million tonnes of oil equivalent—of zero (or near zero) emission fuels by the 2040s[2]. The general consensus is that the scalable and sustainable solution for shipping over the long term will be fuels derived from renewable hydrogen (i.e. e-fuels).

A 2020 study estimated that on the order of $1.6 trillion would need to be directed at landside investment to build sufficient production, distribution and storage of e-fuels to decarbonise shipping by 2050[3]. On the basis that a steady ramp up of e-fuel availability (e.g. along the S-curve or sigmoid curve often used to represent transitions) would require about a quarter of the energy used in shipping to be derived from renewable sources by 2035, approximately $400 billion of this capital would need to be committed by 2030 (i.e. five years in advance of fuel availability, allowing time for the construction phase).

These figures highlight the scale and speed of investment that is required, given that projects will likely take at least five years to progress from conception to the construction of renewable energy assets, facilities to produce hydrogen and synthesise e-fuels, and the associated transportation and storage infrastructure. Therefore, as well as debating the upcoming measures for the shipping industry, the IMO must also address what near-term actions will ensure the future availability of the fuels needed to realise its goals.

Optimal sites for e-fuel production facilities are contingent on several factors. Access to good quality renewable energy is clearly advantageous, and this can open opportunities for developing countries with such resources to supply local, regional or global markets with new energy commodities. However, countries in this circumstance may also face socio-economic barriers—particularly around access to and the cost of capital—that will greatly disadvantage such capital-intensive projects.

Here, action by the IMO could deliver dual outcomes. Support of e-fuel projects in developing nations would help ensure that sustainable fuels are available to the shipping industry in the necessary volumes and within the required timescales. In addition, such support could also contribute to the IMO's remit to ensure a just and equitable transition by helping ensure developing countries are not 'left behind', and that all countries are able to build resilient supply chains, viable domestic industries and improved port infrastructure.

[1] IMO: 2023 IMO Strategy on Reduction of GHG Emissions from Ships

[2] Getting to Zero Coalition: Climate action in shipping 2024

[3] Global Maritime Forum: The scale of investment needed to decarbonize international shipping

This study leverages the wealth of global data available on renewable energy projects to compare the levelised costs of energy (LCOE) in Sub-Saharan Africa against Brazil, India and Australia. It also examines the sensitivity of those LCOEs to key variables such as the quality of the renewables resource, installation / construction costs, and costs of capital. The steps required to produce hydrogen and synthesise e-ammonia are then added to the analysis and, using project financing models, the impact of changes in costs of capital and project timescales are explored, alongside potential support mechanisms to address some of the challenges faced by e-fuel projects in developing countries.

Illustrating the cost sensitivities of renewable energy projects

The production of e-ammonia involves three principal stages: 1) generating renewable energy from (for example) solar PV and/or wind turbines; 2) producing hydrogen from water via an electrolyser using this electricity; and 3) combining the hydrogen with nitrogen to synthesise ammonia. Each of these processes requires significant upfront investment.

There is a considerable amount of public data available on renewable energy generation derived from projects across the world. Data from IRENA's 2023 Renewable Power Generation Costs report[4] has been used to test the cost sensitivities of renewable energy projects in different countries / regions to the following variables:

1. **Installation cost:** This is the total cost of bringing a project to the operational phase; it includes equipment, installation, and civil engineering costs; planning, development and permitting costs; and supply chain margins and fixed financing costs

2. **Cost of capital:** This represents the overall cost of funding a renewable energy project and is typically composed of debt and equity, but represented as a combination of both sources via the Weighted Average Cost of Capital (WACC)

3. **Capacity factor:** This is the measure of the 'quality' of a renewable energy resource and is the proportion of annual generation from the energy assets (e.g. solar PV or wind turbines) relative to its theoretical continuous maximum output

These factors, along with ongoing operational and maintenance (O&M) costs, are used to determine the LCOE for a given project. The levelised cost is the net present value of all the costs associated with building and operating the renewable system divided by the net present value of the energy produced over its lifetime, where the WACC is used to discount projected costs and energy production to present values.

The LCOE is a figure that broadly represents the average cost of generating energy over the lifetime of an energy system and is used to compare costs across different types of energy generation and between different locations. Higher installation and O&M costs, higher costs of capital, and/or lower levels of energy generation will result in higher LCOEs. This study has used data from IRENA to compare LCOEs from utility scale PV and onshore wind generation across different countries / regions and to test the sensitivities to the three key variables—the upfront investment cost, the cost of capital, and the renewables resource quality.

IRENA data is typically presented on a country basis, but is informed by an aggregated dataset of individual projects. This data reflects country-specific factors (e.g. equipment costs, labour costs, costs of capital) and project-specific factors (e.g. scale, associated grid costs, quality of renewables). The need to bridge country-level factors with a reasonable representation of project-level factors highlights the difficulty in comparing LCOEs across countries / regions. In addition, for countries where there has not yet been large-scale adoption of renewable energy, limited data may misrepresent the potential LCOEs of individual projects. Therefore, this analysis is intended to illustrate relative sensitivities rather than absolute cost estimates.

[4] IRENA: Renewable Power Generation Costs in 2023

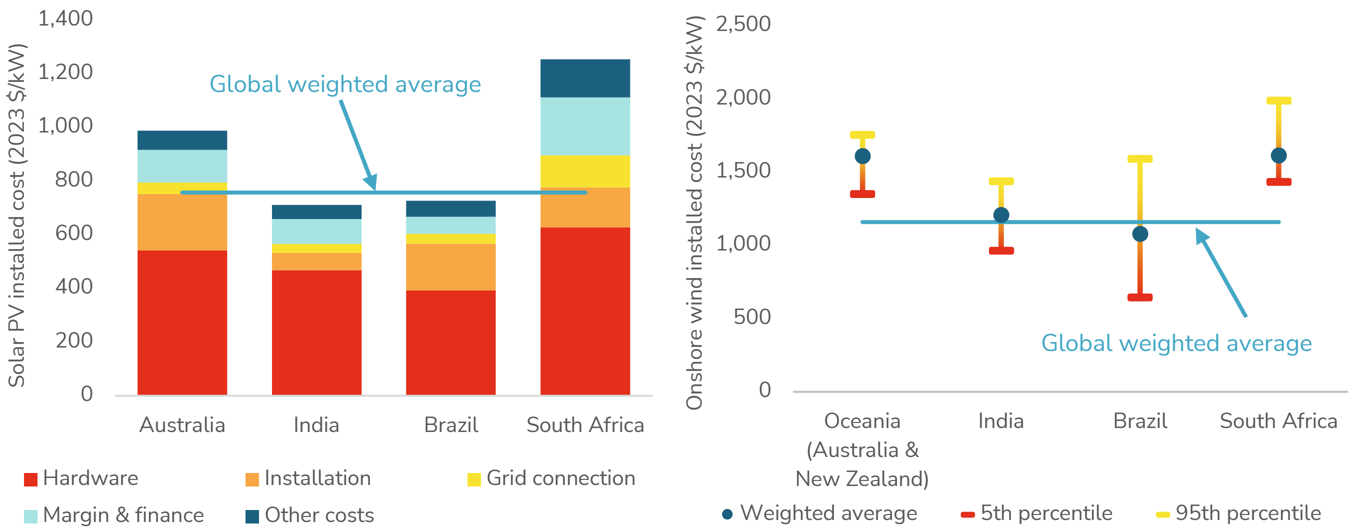
Inferring the impact of geographical variance on the levelised cost of renewable energy projects

Installation cost: Data highlights sources of variance between different countries and ranges in costs within each country

IRENA actively tracks the components of installation cost for utility-scale solar PV projects in over 30 countries. The chart on the left in Figure 1 shows the variance in 2023 total installed cost in four examples—South Africa, Brazil, India and Australia. Although solar PV is a mature technology, there is clear disparity in hardware and installation costs (possibly due to differences in import tariffs, local supply chains, labour costs and project-specific factors such as size and location) as well as in costs associated with development and permitting (under 'other costs'). These costs may fall as a domestic market / supply chain matures. The data also highlights how higher costs of capital—fixed financing costs and margin (i.e. equity) requirements—are embedded throughout the supply chain.

The chart on the right in Figure 1 shows the spread in total installation costs for onshore wind projects in 2023. Cost ranges within a country are likely to reflect factors such as project scale, turbine size, and location-specific challenges (e.g. ease of access, local policies, etc.). However, the level of variance in installed cost emphasises the challenge in deriving generic estimates of levelised costs on a country / regional basis, and how this may misrepresent realisable LCOEs on a project-by-project basis.

Figure 1: 2023 installed cost by country / region for solar PV (left) and onshore wind (right)

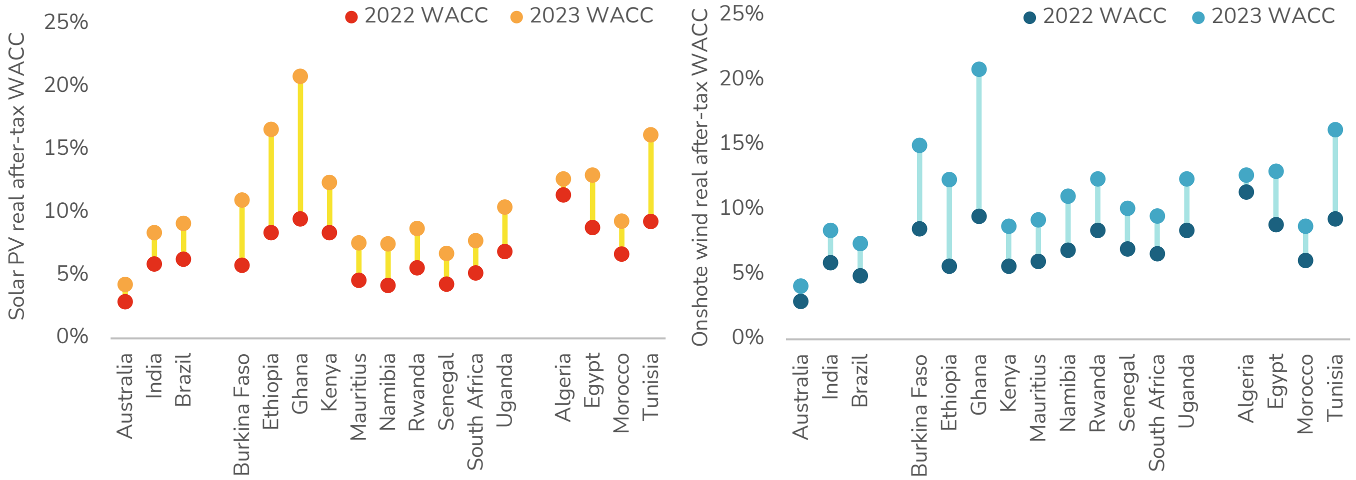


Source: *IRENA: Renewable Power Generation Costs in 2023*

Cost of capital: Clear divergence in WACCs between developed and developing countries and in the impact of recent inflation

In 2021-2022, IRENA undertook extensive research to determine realistic costs of capital for renewable energy projects in different countries by bolstering the data derived from its auctions and PPA database with industry surveys and interviews. As a result, a benchmarking tool was developed to track real after-tax WACCs in 99 countries for utility-scale solar PV and onshore wind projects. The figures for 2022 and 2023 are shown in Figure 2.

Figure 2: 2022-2023 real after-tax WACC estimates for solar PV (left) and onshore wind (right) projects



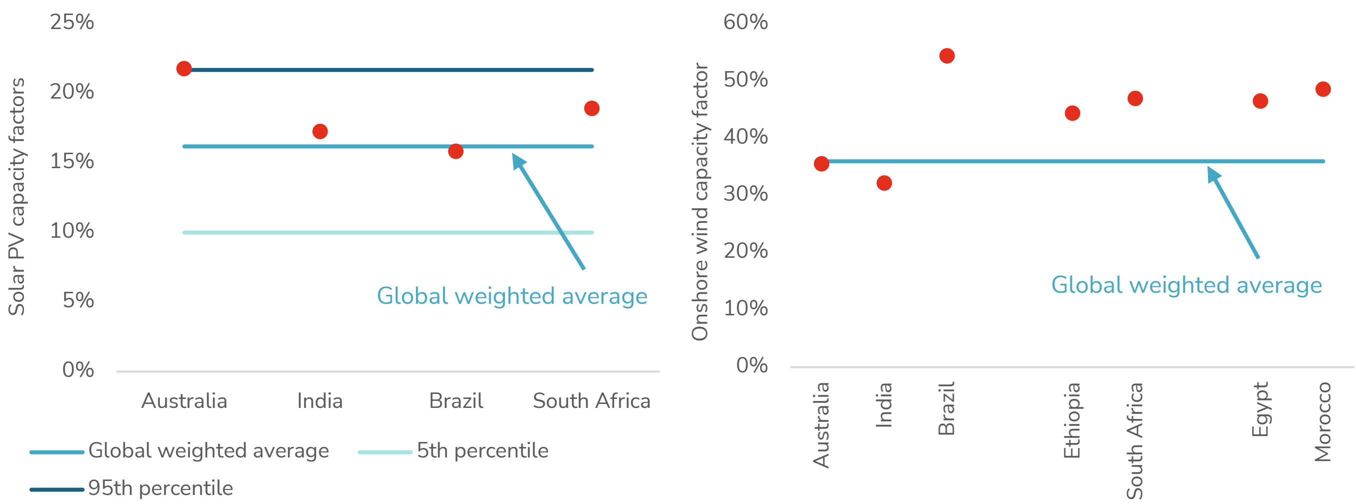
Source: *IRENA: Renewable Power Generation Costs in 2022*; *IRENA: Renewable Power Generation Costs in 2023*

This data indicates a clear disparity in the cost of capital between developed (Australia) and developing countries. Large variance across African nations can also be seen (although lack of relevant renewable energy projects and/or data on such projects may affect estimates for some of these countries), along with an uneven response to the 2022-2023 inflationary period as well as the resulting shifts in interest rates and country-specific risk.

Capacity factors: Countries selected for comparison typically exhibit renewables resource quality greater than global weighted average

The capacity factor represents the amount of useful power obtained (typically averaged over the year), relative to the installed power capacity (e.g. solar PV / wind). It is a function of the climate and weather patterns and conditions at the installation location, and so varies between and within countries. Figure 3 shows average capacity factors for solar PV and onshore wind projects installed in 2023 in Australia, Brazil, India and across the small number of African countries tracked by IRENA.

Figure 3: 2023 capacity factors for solar PV (left) and onshore wind (right) projects



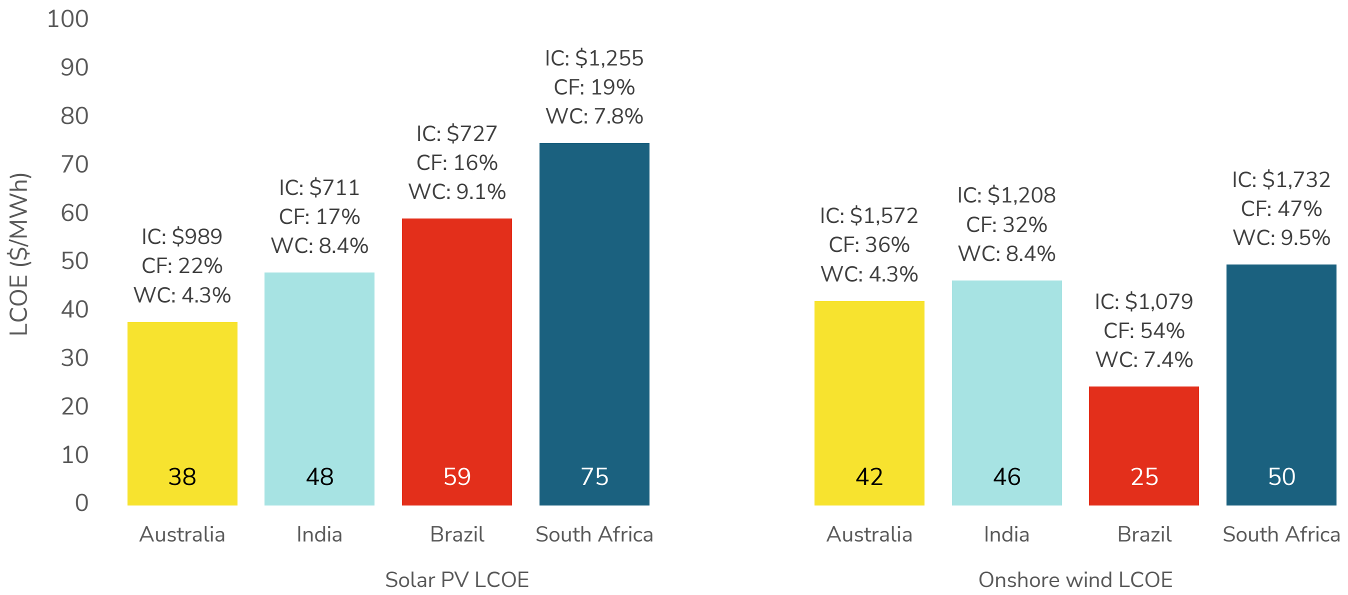
Source: *IRENA: Renewable Power Generation Costs in 2023*

Capacity factors for utility scale solar PV span a narrower band than those for onshore wind. IRENA estimates that the global weighted average for solar PV in 2023 was 16.2% and the derived capacity factors in Australia, Brazil, India and South Africa sit in the upper band of that range. Capacity factors for onshore wind projects again indicate that those in Australia, Brazil and India fall either close to or above the global weighted average; the data available for African countries indicate that strong wind resources are also available across the continent.

Levelised costs: Countries with better renewables resource will struggle to compete against countries with lower costs of capital

Levelised costs are a function of installed cost (and ongoing O&M), capacity factor and the WACC (which is used to discount cash flows and energy output over the lifetime of the assets to present values). Figure 4 shows the 2023 LCOEs in Australia, Brazil, India and South Africa, derived from the input assumptions for each country described above, with each key variable stated.

Figure 4: 2023 LCOEs for solar PV and onshore wind projects with applied installed cost (IC), capacity factor (CF) and WACC (WC) highlighted



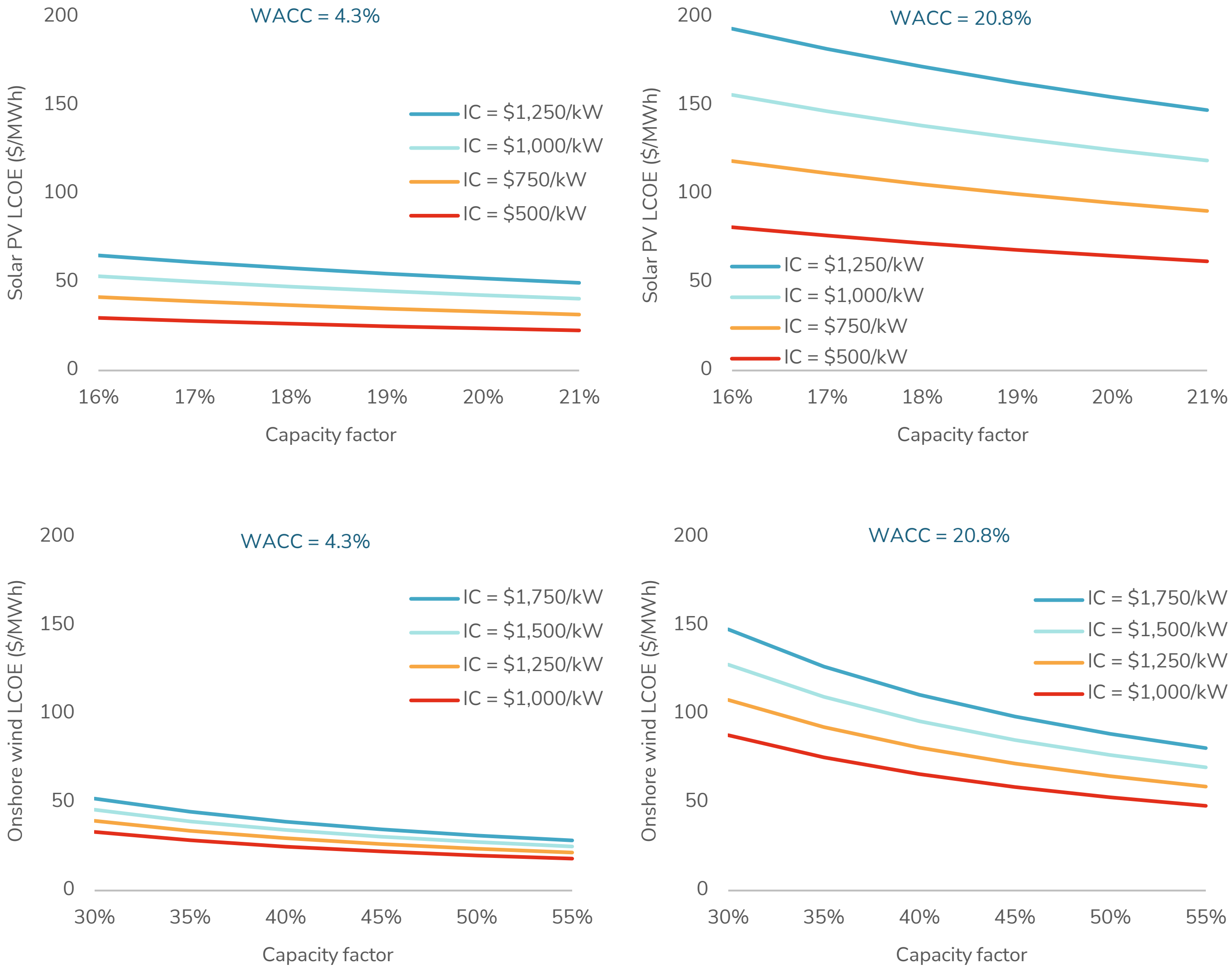
Source: *IRENA: Renewable Power Generation Costs in 2023**;** approach and additional assumptions detailed in Appendix.*

The combined impact of installed costs, capacity factor and WACC on relative LCOEs can be discerned at the extremes. For instance, comparing onshore wind LCOEs in Brazil and Australia indicates that the high capacity factor and low installation costs in Brazil drive LCOEs far lower than in Australia despite Brazil's higher WACC. On the other hand, despite similar solar PV installation costs in Brazil and India, the LCOE of the former is materially higher due to the larger WACC and marginally lower capacity factor.

To fully understand the relative sensitivity of LCOEs to changes in each individual variable, one component can be fixed while the other two are flexed. However, IRENA's dataset is limited to actualised projects (i.e. those that are economically viable) and thus, across sub-Saharan Africa, it has only tracked South African utility-scale solar PV and onshore wind projects in 2023. So, to assess the potential range in LCOE that could be achieved across the wider continent, the upper bound in WACC found across Africa (20.8% in Ghana, as indicated in Figure 2) has been applied.

Figure 5 illustrates the sensitivity of solar PV and onshore LCOEs to a range of plausible installation costs and capacity factors, under the lower (Australia; 4.3%) and upper (Ghana; 20.8%) bounds of WACC considered.

Figure 5: Solar PV (top) and onshore wind (below) LCOEs derived for ranges of installed costs and WACCs—4.3% (left) and 20.8% (right)



The analysis shows that the higher the WACC (which is applied as a discount factor), the greater the influence it has on the sensitivity of LCOEs to variance in installed costs and capacity factors. For solar PV, where the viable range in capacity factor is relatively constrained, the economic feasibility of projects are more sensitive to changes in WACC and, at high WACCs, more sensitive to changes in installed costs. Given the wider range of possible capacity factors in onshore wind, there is more potential for achieving lower LCOEs through access to high-quality wind resource. However, even where coupled with lower installation costs, such projects would still be uncompetitive if reliant upon the higher costs of capital found in some African countries.

Determining the cost sensitivities of e-fuel projects in different regions

Modelling e-ammonia projects with varying installation costs, capacity factors and WACCs

To compare e-ammonia production in Australia, Brazil, India and Africa, equivalent sized large-scale projects (delivering 1 million tonnes of e-ammonia per annum) have been modelled. It has been assumed that the renewable energy generation supporting these plants utilise the same proportions of solar PV and onshore wind, but country-specific installation costs and capacity factors have been used (with South African values used as a proxy for Africa). As well as providing a direct cost input into the production facility, the capacity factors determine the rate of utilisation of the electrolyser and so influence its optimal size (and thus its cost). These assumptions summarised in Table 2**Error! Reference source not found.**.

The variance in installation costs for renewable energy projects suggests that construction costs for e-fuel production facilities is also likely to vary between countries (as well as due to project-specific factors such as scale and location). In the absence of country-specific data, however, the same cost assumptions have been applied to the additional facilities required to produce e-fuels across each country / region. This includes costs related to water desalination / wastewater treatment, the electrolyser, hydrogen storage (assumed to be in underground pipes), and ammonia synthesis. The onward transportation of e-ammonia is excluded from the analysis. These assumptions can be found in the Appendix.

It is important to note the simplifications that have been necessary in this analysis. In practice, there will be even greater variation in the competitiveness of individual projects within and across countries than indicated by the ranges of installed costs, capacity factors and LCOEs seen for renewable energy projects. Site-specific factors such as access to water and grid connectivity are likely to have a material impact on project costs. Proximity and access to local, regional or global markets will also be crucial. The intent of this analysis is not to provide conclusive insights into the relative costs of e-ammonia produced in different locations, but to highlight the critical role that access to and costs of funding play in driving differences in competitiveness, even if all other factors are equivalent.

In the absence of public data on e-ammonia projects and their WACCs, the costs of capital of renewable energy projects have been used to estimate e-ammonia project costs. This is a reasonable proxy for e-fuel production given similar types of project financing will be required. However, a facility built to export e-fuels will have a different risk profile to renewable energy projects supplying the domestic grid. Some of the risks faced by such projects are listed below.

1. **Jurisdiction risk:** This covers country-based risks (political, legal, social) which both types of projects will likely be exposed to.

2. **Default risk:** This is the risk that an offtaker defaults on its purchase agreement and could be commensurate with a sovereign risk if offtaker is a state-backed utility (e.g. for a renewable energy project). For an e-ammonia project, it will be linked to the credit quality of the corporate (potentially international) offtaker(s).

3. **Currency risk:** This results from exposure to changes in currency exchange rates which affect the returns that providers of capital receive (although it can also apply during the construction period if causing installation costs to fluctuate). A domestic renewable energy project will be exposed to currency risk, but an e-ammonia project could negate this risk if offtake is agreed in the same currency as the funding source.

4. **Market risk:** This is price risk that stems from selling uncontracted e-ammonia into the market or following expiration of initial offtake agreements. Equivalent risk for domestic renewable energy projects may be lower if offtake is of longer duration.

5. **Technology (construction / operation) risk:** Renewable energy is a mature industry which has experienced decades-long learning curves and achieved considerable cost reductions. Ammonia synthesis is also a well-established process. However, large-scale electrolysers have yet to be built and so present a technology risk which could occur during construction (delays and/or cost overruns) or operational phase (lower than expected efficiency or higher than expected O&M costs).

To model e-ammonia production costs across a project lifecycle, funding has been incorporated with greater sophistication than by applying a simple WACC to discount cash flows and output volumes. Broad estimates for the loan duration and amount, cost of debt, and target equity return (Table 1) were sourced from the IEA's Cost of Capital Observatory—a survey-based assessment of financing of renewable energy projects in a handful of developing countries.

Table 1: Funding assumptions applied in modelling comparative e-ammonia production

	Australia	India	Brazil	Africa
Loan tenor (duration of borrowing period)	15 years	15 years	15 years	15 years
Leverage (proportion of debt as % of construction cost)	80%	70%	55%	45%
Cost of debt (interest rate charged on debt)	5%	8.5%	10.0%	12.0%
Target equity return (for the residual capital that is not debt)	7.5%	13.0%	14.0%	15.5%
Corporate tax rate	30%	30%	34%	27%
Derived WACC	4.3%	8.1%	9.9%	12.4%

Source: *Loan tenors, leverage, cost of debt and equity target from IEA: Cost of Capital Observatory; Corporation tax from Damodaran: Country Risk Premiums (weighted average used for Africa)*

Average figures for 2021-2022 solar PV projects from the IEA's database have been used to represent India and Brazil. The derived WACCs are close, but do not exactly match, IRENA's 2023 solar PV WACCs. The most conservative figures from the IEA have been used to represent projects in Africa and these generate a WACC roughly in line with the average of IRENA's 2023 WACCs for African countries. The Australian figures were derived to align with IRENA's 2023 solar PV and onshore wind WACCs.

In a similar manner to the calculation of LCOEs, the levelised cost of production of hydrogen and e-ammonia can be calculated by discounting the capital and operating costs over the life of the plant and dividing by discounted output volumes. Using the WACCs derived in Table 1 to discount costs and output volumes, the LCOE, LCOH (levelised cost of hydrogen) and LCOA (levelised cost of e-ammonia) have been calculated at each production stage (Table 2).

Table 2: Project specification and estimated LCOE, LCOH and LCOA for each country / region

		Australia	India	Brazil	Africa
Solar PV capacity	GW	1.9	2.4	2.6	2.2
Solar PV capacity factor		22%	17%	16%	19%
Solar PV installation costs	$/kW	989	711	727	1,255
Onshore wind capacity	GW	1.7	1.9	1.1	1.3
Onshore wind capacity factor		36%	32%	54%	47%
Onshore wind installation costs	$/kW	1,572	1,208	1,079	1,732
Assumed electrolyser load	Hours/year	3,498	3,123	5,048	4,449
Electrolyser capacity	GW	2.5	2.8	1.7	1.9
LCOE	$/MWh	41	46	43	78
LCOH	$/kg H_2	3.5	4.4	3.7	5.9
LCOA	$/tonne NH_3	805	991	830	1,264

The impact of variations in installed costs, capacity factors and WACCs can be interpreted from these figures. Low installation costs and strong onshore wind resources bring Brazil's LCOE on par with Australia, despite the differences in WACC. The higher capacity factors also result in increased utilisation of the electrolyser (which means a smaller sized electrolyser is needed), thereby allowing Brazil to deliver an LCOH and LCOA in line with Australia, despite the capital-intensive processes involved and higher costs of capital in Brazil (relative to Australia).

Applying a project finance model to e-ammonia production highlights sensitivity to capital costs

Levelised cost modelling applies a constant discount rate (the WACC) to costs over the life of the project to estimate the present value of those costs and so assumes that timing of cash flows from and to providers of debt and equity are proportionate. This approach of applying a constant discount rate obfuscates some of the differences that can occur in practice between projects in different countries (depending on their existing investment practices and the availability of different types of capital and equity). Therefore, in addition to the levelised costs estimated in Table 2 from the WACCs derived in Table 1, this study also assesses the relative competitiveness of e-ammonia production if a project finance model is applied. This type of model allows for the following functionality to be added to the analysis:

6. Lead times for development and construction proceeding the operation of the facility can be incorporated and installation costs spread over this period

1. Debt and equity can be modelled over different timescales (e.g. debt over a 15-year tenor and equity over a 25-year project life)

2. The impact of variable pricing for the energy / fuel produced can be assessed

The simple project finance model constructed leverages each of these elements. In the base case, project development (pre-FEED through to FID) and construction is modelled over a seven-year period broken down into three steps shown in Table 3.

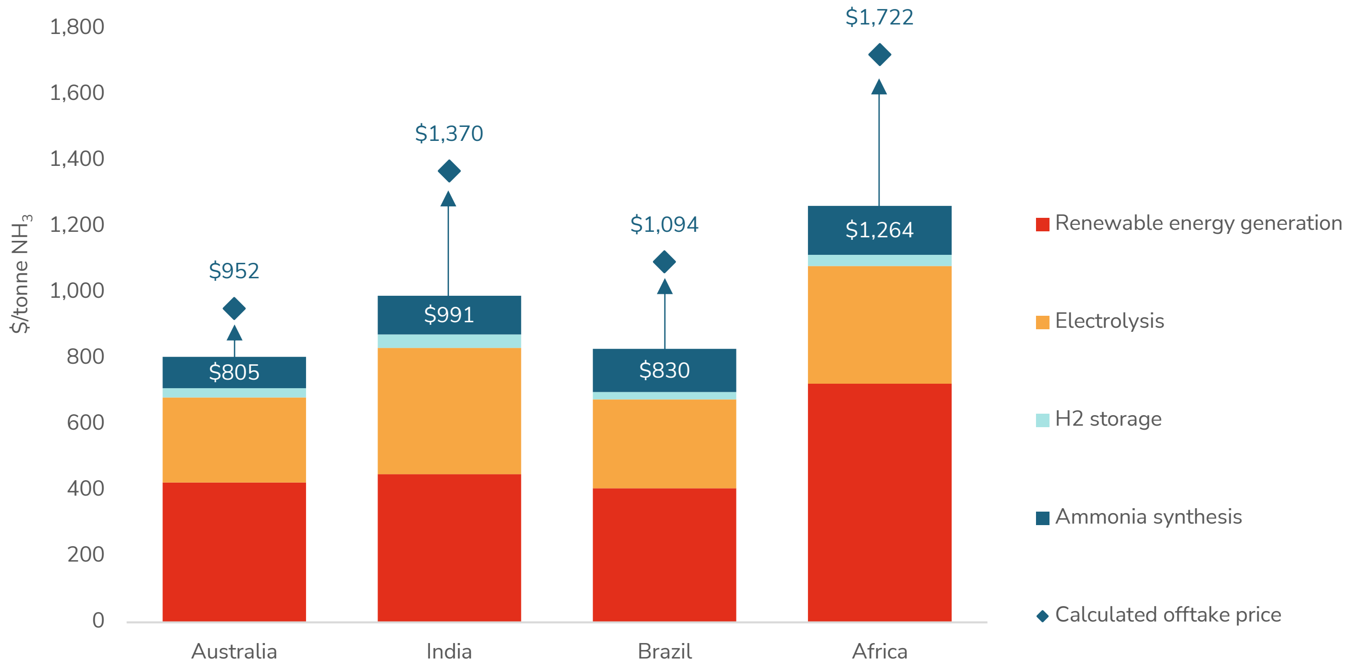
Table 3: Project timescales modelled

Project phase	% of construction cost	Duration (years)
Lead up to FEED (Front End Engineering Design)	1%	1
Lead up to FID (Final Investment Decision)	4%	3
Construction phase	95%	3

Source: *Base case based on [World Bank: Scaling Hydrogen Financing for Development]*

Equity is fully drawn before debt and once the plant is operational, the debt is repaid over a 15-year period, in line with the assumed duration of the initial offtake agreements. The economic life of the production facility is assumed to be 25 years and so, for the last ten years of operation, the e-ammonia is sold at market price (assumed to be $1,000/tonne NH_3). The offtake price that delivers the target return of equity over the 25-year period is then derived (Figure 6).

Figure 6: Components of LCOAs and the required offtake price derived from equity targets



Under a project finance model, the required price for the e-ammonia offtake over the first 15 years of the project is always greater than indicated by the LCOA estimate produced using a WACC (Table 2). This is due to the development / construction lead time before revenues are generated, the uneven time horizons for debt and equity and (to a lesser extent) the impact of merchant risk in the last ten years of the project. The higher the WACC, the greater the variance (all else being equal). So, although the Brazilian LCOA is on a par with the Australian value, the derived offtake price is 15% higher.

Unsurprisingly, with the lowest leverage and highest cost of capital, Africa suffers the largest absolute penalty due to the lock-up of greater proportions of equity during the unproductive construction period. This heightens construction risk—for example, for each year a project is delayed in Africa, the required e-ammonia offtake price compounds by 10%, while delays in an equivalent Australian project increases the price by 5% per annum.

Overall, with approximations made by holding many of the other parameters constant, the analysis illustrates the significant differences in calculated offtake price that can be associated with equivalent / similar projects located in different regions. In doing so, it highlights how this difference is heightened in countries already disadvantaged in access to debt finance and exposure to higher costs of capital.

Under the indicative capacity factors (i.e. those for 'raw' solar and wind resource quality) used, African projects would, on the basis of the renewables resource, be expected to be highly competitive. However, once the types and costs of capital are included within a project-finance model, there are major differences observable in the prices of offtakes that would need to be secured to unlock project FID. Based on the above example, project developers would need to find customers (e.g. bunker purchasers), willing to pay an 80% premium for e-ammonia from African projects compared with an Australian product. In practice, this would likely mean that projects in Africa would be unable to secure the offtake agreements needed to reach FID, and thus projects would either fail to secure finance or take on significant risk of default.

What type and scale of support could help drive investment for projects in developing countries?

Grants and/or concessional lending could help offset the funding disadvantage faced by projects in developing countries

In the example modelled, Australia has the lowest required offtake price and therefore serves as the benchmark for this study for testing the potential types and levels of support needed for countries that could have a strong capacity for e-fuel production but suffer from lack of access to and/or higher costs of capital.

To first test the potential outcome from support mechanisms that could reduce some of the differences in installation costs between advanced economies (e.g. Australia) and other countries, a grant in the second year of construction has been introduced for Brazil, India and Africa. The level of support needed by each country to generate a required offtake price equivalent to that of Australia has been calculated. This type of grant has been modelled to act as a tranche of first loss, zero-return equity. By reducing exposure to construction risk this could also potentially improve the investability of the project and so attract lower-risk, lower-cost equity to participate (this further beneficial effect was not modelled, however). The level of grant required to bridge the difference in offtake prices for a facility producing 1 million tonnes of e-ammonia per annum is shown in Table 4.

Further options for supportive mechanisms were also explored, including modelling which calculated the impact of combining a grant with concessional finance. This assumed that the same debt terms accessed in Australia (80% leverage and 5% cost of debt) were extended to Brazil, India and Africa. With those parameters for leverage and cost of debt, the grant needed to then reach Australia's required offtake price was again calculated. For Brazil, the increased leverage and lower cost of lending negated the need for a grant. For India and Africa, the provision of concessional finance roughly halved the amount of grant needed.

Table 4: Grants that bridge the difference in offtake prices between Australia and Brazil, India, and Africa (without and then with concessional finance)

	Australia	India	Brazil	Africa
Upfront capital investment ($m)	8,680	7,743	5,807	7,541
Required offtake price without any grant or concessional lending ($/tonne NH_3)	952	1,370	1,094	1,722
Grant needed to bring required offtake price in line with Australia if no concessional lending ($m)	-	1,274	396	1,922
Grant as % of upfront capital investment	-	16%	7%	25%
Grant needed to bring required offtake price in line with Australia with concessional lending at rates equivalent to Australian leverage / cost of debt ($m)	-	733	-	872
Grant as % of upfront capital investment with concessional lending	-	9%	-	12%

Estimating the scale of support needed to drive geographically and economically diverse investment in e-fuel production

The analysis presented in Table 4 provides a basis for estimating the 'order of magnitude' of the amount of support that would be needed to level out of some of the inherent access and cost of capital disadvantages that are a feature of low-income countries.

The introduction of this report identified that approximately $400 billion in capital needs to be committed (i.e. reach FID) by 2030 in order to unlock e-fuel production at the volumes required to achieve IMO's Revised GHG Strategy targets. If that capital were to be distributed evenly across the four country / region examples used in this study, then the grant needed per project can be extrapolated to a share of that $400 billion by location. Table 5 summarises the results of this calculation and indicates that the total grant support that would be needed by 2030 with no concessional finance is of the order of $47 billion (cumulative). However, if concessional finance of an appropriate scale was made available, then the level of grant support required would fall to $21 billion.

Table 5: Total level of grant required to promote capital investment of $400 billion (without and then with concessional finance)

	Australia	India	Brazil	Africa
Share of total capital invested	25%	25%	25%	25%
Total grant amount needed to bring required offtake price in line with Australia if no concessional lending ($bn)	-	17	5	25
Total grant amount needed to bring required offtake price in line with Australia with concessional lending at rates equivalent to Australian leverage / cost of debt ($bn)	-	10	-	11

Support for e-fuel projects could help offset the impact of IMO GHG policy

The shipping industry's need for a low-cost zero emission alternative fuel is increasingly converging on ammonia produced from 100% renewable electricity, and so the hunt is now on for the locations that have the strongest potential to be producers of this new energy commodity. Given shipping's global operations and the ability to produce a fuel where it is cheapest and then transport it to key bunker hubs (or create new bunker hubs), the search for optimal sites has been globally inclusive.

In much of the wider analysis conducted so far, the focus has often been on the quality of the renewables resource—the strength and consistency of the sun and/or wind—in different parts of the world[5]. Locations around the equator and significant numbers of countries in the global south, and often Africa, have been identified as prime renewable real estate. To date, however, the track record in deployment rates of renewable energy projects in the global south has been underwhelming[6]. The explanations are myriad, but often relate to lack of access to capital, the cost of capital, and challenges relating to capacity, planning and processes.

This paper's analysis builds upon the wealth of information available on renewables projects across different countries, and in relation to the investment factors, risks and costs associated with such projects. This data is then leveraged to illustrate the relative competitiveness of e-ammonia production that might be expected in different countries / regions. The findings indicate that similarly sized projects (i.e. controlling for economies of scale) in Brazil, India and Africa would all be uncompetitive relative to projects in Australia, despite comparable or (particularly for Brazil and Africa) better quality renewable energy resources.

Australia's advantage comes from projects which are more highly leveraged, and also benefit from a lower cost of debt and lower target equity return. Compiling reported values for these parameters indicates a WACC (Weighted Average Cost of Capital) for Australian e-ammonia projects of less than 5%, a range of 8% to 10% for Brazilian / Indian projects, and 8% to 20% for African e-ammonia projects. The cost of capital differences more than compensate for any differential in renewables energy quality, and thus favour the Australian project.

Through the application of levelised cost calculations and project finance modelling, the report also highlights that there is a wide range between the long-run (WACC-based) cost of e-ammonia production—approximately $800/tonne NH_3 in the lowest cost locations—and the initial offtake prices that would be needed to secure project-finance investments ($950 to $1,700/tonne NH_3). These offtake prices underscore the importance of policy support that offers certainty and sufficient reward in triggering early adoption.

In light of this, the report assessed how the expected inequity in access to and costs of capital could be corrected for. Two tools were considered: 1) grants—essentially providing zero-cost finance for projects in low-income countries; and 2) concessional finance—below-market-rate loans associated with economic development.

[5] World Bank: The Potential of Zero-Carbon Bunker Fuels in Developing Countries; EDF: Shipping can reduce climate pollution and draw investment into developing countries

[6] Zero Carbon Analytics: Renewables Remain Critically Underfunded in Africa

Under appropriate parameters, these tools can unlock an equitable distribution of investment. For example, to spread $400 billion in capital equitably across the four sample countries / regions selected in this study, an additional $47 billion would be needed in grants (or a combination of grants and concessional finance).

This study did not intend to provide an exhaustive assessment of potential projects or their geographies: many other countries have promising renewables resources and may become competitive producers of e-fuels in the future. There are very likely potential projects that are better and more competitive than those estimated from the generalised statistics and assumptions used in this paper.

The representative sample of locations in this study are instead intended to highlight that as long as IMO policy to incentivise energy transition solely or predominantly consists of an 'equity blind' reward mechanism (e.g. a passive allocation of revenues to subsidise e-fuel production), it is more likely to stimulate projects in developed economies. This approach risks perpetuating existing under-investment in many locations that are better suited in terms of renewables resources, but are subject to capacity constraints, lack of capital and/or high cost of capital. If this were the case, the IMO's policy would be reinforcing existing disadvantages and inequities for these countries, and "leaving countries behind", rather than "contributing to a just and equitable transition".

The design of the IMO's mid-term measures is derived from the IMO's Revised Strategy[7], adopted in 2023, which has multiple references to the need for IMO to contribute to and support not only shipping's energy transition, but also a 'just and equitable transition':

- **Vision statement:** "...aims to phase them (GHG emissions) out as soon as possible, while promoting, in the context of this strategy, a just and equitable transition..."

- **Paragraph 4.5:** "The mid-term GHG reduction measures should effectively promote the energy transition of shipping and provide the world fleet with a needed incentive while contributing to a level playing field and a just and equitable transition."

- **Paragraph 5.3:** "when developing candidate mid- and long-term GHG reduction measures, due account should be taken to ensures a just and equitable transition that leaves no country behind, including supportive measures."

Since the revised strategy was adopted, UNCTAD has carried out a comprehensive assessment on behalf of the IMO of the potential impact on states, arising from different hypothetical policy scenarios[8]. This analysis showed that the economic consequences of IMO GHG policy will be regressive: that low-income countries, particularly SIDS, LDCs and African countries, face the strongest negative impacts from the increases in transport cost (Figure 7) that are an inevitable consequence of a switch away from fossil fuel to fuels produced from renewable energy.

This leads to the question: "given the evidence from UNCTAD on the risks arising from a generalised increase in transport cost, could the opportunity that many low-income countries have associated with the production of renewable fuels provide at least some compensation?". This is consistent with but additive to the multiple obligations in the IMO's revised strategy relating to ensuring a just and equitable transition that leaves no country behind.

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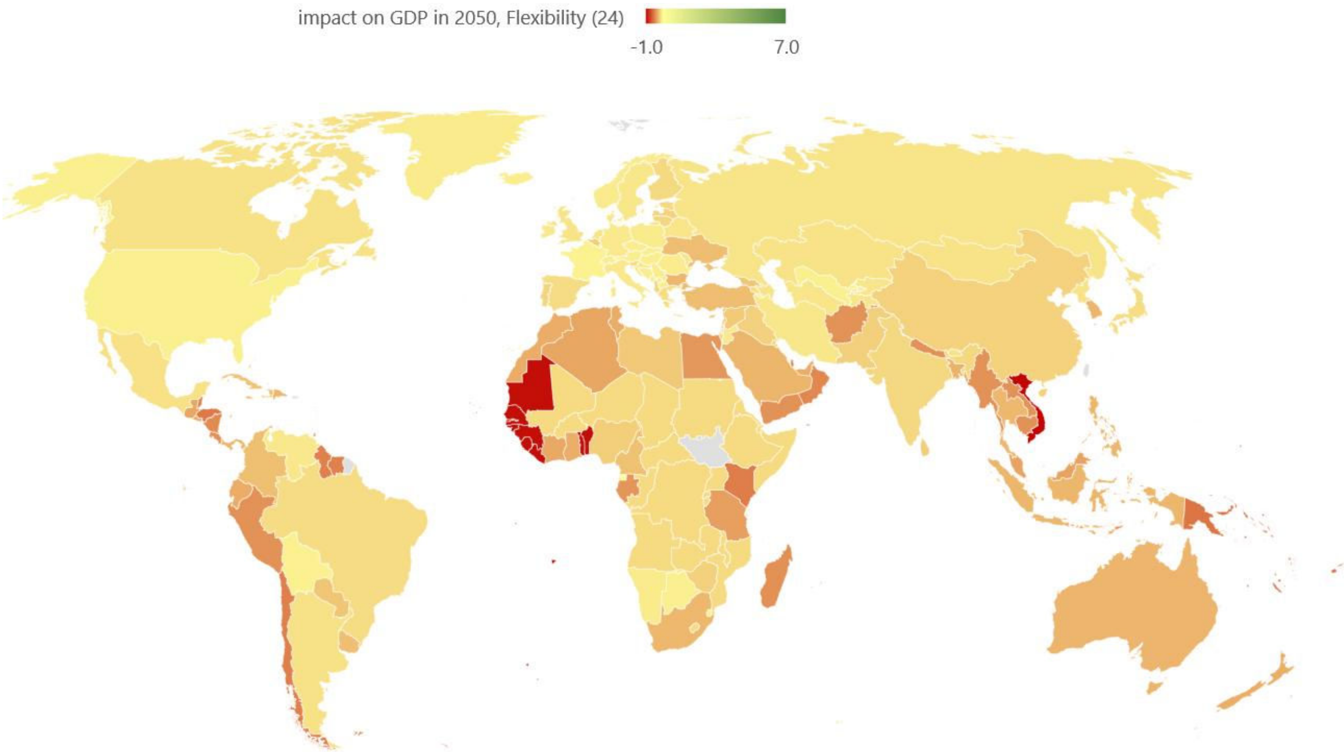
[7] IMO: MEPC 80-17-Add.1 - Report Of The Marine Environment Protection Committee On Its Eightieth Session

[8] Full report can be downloaded from IMODOCS (MEPC 82/INF.8/Add.2); registration is required

Figure 7: Impact on GDP in 2050 under policy scenario 24 (global fuel standard with a flexibility mechanism and no GHG levy)



Source: *[UCL Shipping and Oceans Research Group: New analysis shows a shifting landscape with strong support for a carbon price to reduce GHG emissions from shipping]; See "FAQ on mid-term measures*

Unlocking an equitable distribution of e-fuel investment (e.g. equal amounts across countries of different income status) is not equivalent to addressing the negative impacts that disproportionately impact low-income countries relative to high-income countries. However, this would at least mean that the distribution of investment from equity-blind rewards did not compound the inequities already inherent in the generalised increase in transport cost associated with shipping's transition to use of renewable fuels.

Appendix: Input data, assumptions and sources

Calculating levelised costs and the weighted average cost of capital (WACC)

A levelised cost represents the cost of building and operating an energy or fuel generating plant over its lifetime on a per-unit of production basis. Critically, the associated costs (and output) are discounted to the net present value (NPV), and so the levelised cost equates to the minimum price the energy or fuel must be sold at in order to offset the cost of production under the cost of capital applied through the discount rate.

$$Levelised\ cost = \frac{NPV\ of\ total\ installation\ and\ operating\ costs\ over\ lifetime}{NPV\ of\ energy\ or\ fuel\ produced\ over\ lifetime}$$

Breaking down the components of the levelised cost for renewable energy projects over the project lifetime (t):

$$Levelised\ cost\ of\ energy\ (LCOE) = \frac{\sum_{t=1}^{n} \frac{(Installed\ cost + O\&M\ cost\ in\ year\ t)}{(1 + WACC)^t}}{\sum_{t=1}^{n} \frac{Electricity\ produced\ in\ year\ t}{(1 + WACC)^t}}$$

The levelised cost calculation for the production of hydrogen or ammonia is similar, with total costs and annual production volumes discounted to present values.

The weighted average cost of capital (WACC) represents the cost of funding the project, reflecting the proportions and costs of debt and equity accessed.

$$WACC = Cost\ of\ debt \times \frac{Debt}{Debt + equity} \times (1 - Corp\ tax\ rate) + Cost\ of\ equity \times \frac{Equity}{Debt + equity}$$

The relative amounts of debt and equity determine the capital structure of the project and, along with the costs of debt and equity, reflect the perceived level of risk debt providers and equity holders associate with the project. Low-risk projects can attract higher proportions of debt and at lower costs. This reduces the overall WACC of a project as 1) costs of debt are typically lower than costs of equity due to greater security / lower risk exposure and 2) debt interest is tax deductible.

Renewable energy project data sources, assumptions and calculations

Table 6 shows the IRENA data on renewable energy projects in 2023 across each of the four countries assessed. Table 7 details the sensitivity of the LCOE to changes in capacity factors, installation costs and WACC and is the data represented in Figure 5.

Table 6: Country-specific inputs and assumptions used to calculate LCOEs

		Australia	India	Brazil	South Africa
Solar PV capacity factor	%	22%	17%	16%	19%
Solar PV installation cost	$/kW	989	711	727	1,255
Solar PV O&M cost	$/kW pa	7	4	7	9
Solar PV economic life	Year	25	25	25	25
Solar PV WACC	%	4.3%	8.4%	9.1%	7.8%
Solar PV LCOE	**$/MWh**	**38**	**48**	**59**	**75**
Onshore wind capacity factor	%	36%	32%	54%	47%
Onshore wind installation cost	$/kW	1,572	1,208	1,079	1,732
Onshore wind O&M cost	$/kW pa	28	14	21	21
Onshore wind economic life	Year	25	25	25	25
Onshore wind WACC	%	4.3%	8.4%	7.4%	9.5%
Onshore wind LCOE	**$/kWh**	**42**	**46**	**25**	**50**

Source: *IRENA: Renewable Power Generation Costs in 2023*

Table 7: Sensitivity of LCOE to ranges (solar PV above; onshore wind below)

Solar PV	WACC = 4.3% Installation cost ($/kW)				WACC = 20.8% Installation cost ($/kW)			
capacity factor	500	750	1,000	1,250	500	750	1,000	1,250
16%	30	42	53	65	81	119	156	193
17%	28	39	50	61	76	112	147	182
18%	26	37	47	58	72	105	139	172
19%	25	35	45	55	68	100	131	163
20%	24	33	43	52	65	95	125	155
21%	23	32	41	50	62	90	119	147

Onshore wind	WACC = 4.3% Installation cost ($/kW)				WACC = 20.8% Installation cost ($/kW)			
capacity factor	1,000	1,250	1,500	1,750	1,000	1,250	1,500	1,750
30%	33	39	46	52	88	108	128	148
35%	28	34	39	45	75	92	110	127
40%	25	30	34	39	66	81	96	111
45%	22	26	30	35	59	72	85	99
50%	20	24	27	31	53	65	77	89
55%	18	22	25	28	48	59	70	81

E-ammonia production data sources and calculations

Table 8 shows the data used to calculate costs at the key stages of e-ammonia production and Table 9 breakdowns the LCOA and required offtake price (the data presented in Figure 6).

Table 8: Assumptions applied in each step of e-ammonia production

Production phase	Variable	Unit	Input data	Source
Water supply (desalination)	CAPEX	USD/tonne H_2O/year	2.7	PtX Business Opportunity Analyser; 2023 cost basis
	Annual OPEX	% of CAPEX/year	4%	
	Electricity input	kWh/tonne H2O output	3	
Electrolysis	CAPEX	$/kW	1,211	PtX Business Opportunity Analyser; 2023 cost basis
	Annual OPEX	% of CAPEX/year	2%	
	Efficiency	kWh H_2 LHV/kWh	69%	
	Water input	Tonnes H_2O/Tonne H_2	10.1	
Hydrogen storage (underground pipelines)	Storage capacity	Tonnes H_2	Variable	Fasihi et al; 2023 cost basis; hydrogen storage sufficient to ensure minimum of 80% load factor for ammonia synthesis process
	CAPEX	$/kg H_2	494	
	Annual OPEX	% of CAPEX/year	2%	
	Variable OPEX	$/kg H_2	4.5	
Ammonia synthesis	CAPEX	$/Tonne NH_3 output/year	819	Fasihi et al; 2023 cost basis
	Annual OPEX	% of CAPEX/year	5%	
	Electricity input	kWh/kg NH_3	0.738	
	Conversion	%	99%	
	H2 input	Tonnes H_2/Tonne NH_3	0.179	

Table 9: Breakdown of e-ammonia production costs

	Australia	India	Brazil	South Africa
Renewable energy generation	424	449	406	724
Electrolysis	258	384	270	358
H2 storage	28	40	23	34
Ammonia synthesis	95	118	131	149
LCOA	**805**	**991**	**830**	**1,264**
Required offtake price	**952**	**1,370**	**1,094**	**1,722**
% difference	18%	38%	32%	36%